October 28, 2013

E3 Reply Comments to 2013 Draft NEM Study

Scope

This document responds to comments received on the Draft 'California Net Energy Metering Evaluation' study released by the CPUC in September 2013. Per direction from the California Public Utilities Commission (CPUC), comments were limited to 5 pages and were to focus on 'calculation errors' applied to the methodology already commented on by stakeholders in November and December 2012. Comments were received by eight parties: Bloom Energy, Inc. (Bloom), The Alliance for Solar Choice (TASC), The Vote Solar Initiative (Vote Solar), The Interstate Renewable Energy Council (IREC), The Solar Energy Industries Association with the California Solar Energy Industries Association (collectively, the Joint Solar Parties or JSP), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). This document categorizes the stakeholder comments received, and provides a response to each comment. To the extent that changes in the analysis were made, they are indicated and reflected in the final report, released in conjunction with these reply comments.

Comments

Comments are organized into six categories. To the extent that multiple stakeholders had the same comment, these are addressed in the same response.

<u>Categories of Comments</u>

1. Comments on Load Shapes, Capacity Factors, and Customer Characteristics
2. Comments on the Avoided Costs
3. Comments on the Calculation of Avoided Bills
4. Comments on the Full Cost of Service
5. Requests for Report Clarification and Additional Analysis
6. Requests to Change Analysis Methodology (out of scope given CPUC direction)

A high level summary of all of the comments by each party is provided in the following pages organized by category. The page number of the comment by each stakeholder in their comments is also provided.

Comment Type	#	Summary of Comment	Stakeholder (Page Number of Comment)							
			Bloom	TASC	Vote Solar	IREC	JSP	PG&E	SCE	SDG&E
Customer Loads and Generation	1	The capacity factor used for fuel cells is incorrect	p. 2							
	2	The NEMFC efficiency assumptions are unclear	p. 2							
	3	The residential/non-residential breakdown of installed NEM capacity forecasts are incorrect						p. 5		p. 3
	4	The CSI case has a non-intuitive breakout of residential vs. non-residential participants							p. 3	
Avoided Cost	5	NEMFC systems should be credited for avoided emissions costs	p. 2							
	6	The resource balance year should be changed		p. 3	p. 1	p. 3		p. 4		
	7	Concerned substation load was not converted to TMY		p. 4						
	8	A high-voltage transmission deferral component should/should not be added to the avoided cost calculations		p. 5	p. 2			p. 4		
	9	T&D marginal costs do not match the most recent SCE and SDG&E GRC marginal costs; Cost of Service and Avoided Costs use different T&D marginal cost values		p. 5	p. 3					
	10	There is a spreadsheet error in the allocation of capacity costs in the E3 Avoided Cost Model		p. 5	p. 4					
	11	SONGS should be removed from the resource balance year calculation		p. 5	p. 5					
	12	Market heat rates should use post-SONGS values; SONGS should not be considered an available capacity resource		p. 5	p. 5	p. 3				
	13	Add additional distribution and integration costs to the cost of service and avoided cost calculations						p. 2		

			Stakeholder (Page Number of Comment)							
Comment Type	#	Summary of Comment	Bloom	TASC	Vote Solar	IREC	JSP	PG&E	SCE	SDG&E
Avoided Cost	14	The avoided RPS procurement costs are overstated						p. 3		p. 4
	15	Discount RPS avoided costs in years prior to 2020 because the IOUs have already procured resources to meet projected load						p. 3		p. 5
	16	NEM generation increases the need for flexible capacity; this should be included as a cost, and the capacity additions should be added to the supply stack						p .4		p. 5
	17	The approach to valuing capacity prior to the resource balance year artificially inflates the annual capacity value						p. 4		
Bill Impact	18	Residential minimum charges should be included in the bill calculations		p. 4&5	p. 1					
	19	The GHG costs used in retail rate escalations are too high because they do not assume return of GHG allowance revenues		p. 5	p. 1					
Cost of Service	20	The SDG&E distribution capacity cost allocation should be justified				p. 3&4				
	21	Gross regulatory items should be used in the net cost of service calculations						p. 2		p. 4
	22	Confirm that the cost of service model uses EPMC scalars correctly							p. 3	
	23	Cost of service should use gross load to calculate subtransmission and transmission costs in SCE's Base Case							p. 4	

			Stakeholder (Page Number of Comment)							
Comment Type	#	Summary of Comment	Bloom	TASC	Vote Solar	IREC	JSP	PG&E	SCE	SDG&E
Additional Information and Analysis	24	Publicly release data and/or SAS codes		p. 1						
	25	Add a sensitivity in which NEM is valued at 100% of the renewable premium		p. 2	p. 1		p. 2			
	26	Add a sensitivity with the assumption that the RPS is raised to 50% by 2030		p. 2						
	27	Perform a PAC and/or TRC test; analyze participant and/or societal impacts		p. 2&3	p. 1					
	28	Explain substation allocator aggregation to climate zones		p. 4						
	29	Display annual NEM impacts over the 20-year period		p. 5						
	30	Report results by rate schedule in the body of the study		p. 5	p. 2					
	31	The high avoided cost case has lower avoided capacity costs than the base and low cases		p. 5	p. 4					
	32	Vintaged ELCC should be clarified and used in the Base Case		p. 5	p. 4					
	33	Include a summary of results and limitations of the report, including a list of caveats				p. 1				
	34	Change the framing of the cost of service results and/or the terminology used in this section				p. 2		p. 1&2	p. 4	
	35	Add a discussion of A.B. 327				p. 2				
	36	Calculate the cost of service results using the median contribution from NEM customers rather than the average						p. 2		
	37	Provide a breakout of the cost of service results by dwelling type						p. 2		

Comment Type	#	Summary of Comment	Stakeholder (Page Number of Comment)							
			Bloom	TASC	Vote Solar	IREC	JSP	PG&E	SCE	SDG&E
Additional Information and Analysis	38	Eliminate the characterization of behind-the-meter generation and consumption as energy efficiency						p. 3		
	39	There is a sentence with incorrect information concerning the income analysis						p. 5		
	40	Provide a breakdown of the income results by decile						p. 5		
	41	Explain how rate design changes since 2010 have impacted results relative to the 2010 study results					p. 2			
	42	Tables 4 and 5 on page C-26 are identical							p. 3	
Methodology	43	Eliminate or reframe the Export Only or All Generation analyses		p. 1	p. 1	p. 2	p. 1	p. 2		p. 2
	44	Use current rates instead of 2011 rates		p. 1	p. 1					
	45	The study should use existing methods to allocate generation and distribution capacity costs		p. 3&4						
	46	CARE customers should be excluded/included from the IOU median household income calculation		p. 4	p. 1			p. 5		
	47	The 2012 lifecycle analysis should be emphasized more in the report			p. 1	p. 3	p. 2			
	48	Median income of homeowners in CA should be used instead of median CA household income in the income analysis				p. 4				

Reply to Comments

Comments on Customer Loads and Generation Resources

1. The capacity factor used for fuel cells is incorrect

In the absence of meter data for individual NEM fuel cell installations, our analysis assumes a 68% DC capacity factor for all fuel cells participating in NEMFC. This value originates from the CPUC's most recent Self-Generation Incentive Program impact evaluation[1], which reports the average annual capacity factor for all metered DG fuel cells in 2011 at 68%.

2. The NEMFC efficiency assumptions are unclear

The efficiency of fuel cells, while important for the overall economics of fuel cells, is not an input into the estimation of ratepayer impact of NEMFC. No assumption was made in how much fuel is consumed to generate the estimated fuel cell output since ratepayers are not paying that cost.

3. The residential/non-residential breakdown of installed NEM capacity forecasts are incorrect

There are two drivers of this observation in the analysis effort; one of which was an error in the calculation first identified at the NEM stakeholder workshop, the other forecast methodology. The error showed unrealistic capacity factors for some customer segments, in particular for SDG&E. This was a result of bad data in the customer binning process and has been corrected. Due to this correction, SDG&E now has more residential NEM generation than non-residential, as is the case. The second driver of this is that the forecast methodology uses an analysis of historical trends based on data through 2011. Since the key market drivers such as retail rate levels, availability of the CSI incentive, and NEM generation costs are in flux, the historical trend will not be a perfect indicator of future NEM adoption. However, this analysis methodology was left unchanged. We believe that the key driver is the quantity of overall NEM and the relative size of residential and non-residential systems. With the correction to capacity factor issue identified above, we believe that both are now correct.

4. The CSI case has a non-intuitive breakout of residential vs. non-residential participants

We agree that the CSI case has non-intuitive breakout of customer classes. The customer breakout reflects the relative size of the CSI incentives originally allocated to each customer class. We include the CSI case because it is required in statue. An additional non-intuitive factor in the CSI case is that the CSI incentives are exhausted in different years depending on adoption pattern. Therefore, the CSI case measures the ratepayer impact of PG&E residential systems installed through 2013 plus non-residential systems installed through later years.

[1] See *CPUC Self-Generation Incentive Program—Eleventh Year Impact Evaluation Report*, Appendix A, Table A-10. http://www.cpuc.ca.gov/NR/rdonlyres/EC6C16C5-9285-4424-87CF-4A55B0E9903E/0/SGIP_2011_Impact_Eval_Report.pdf

Comments on the Avoided Costs

5. NEMFC systems should be credited for avoided emissions costs

We agree that, from a ratepayer perspective, NEMFC systems provide an avoided emissions cost benefit since CO2 allowances would be part of the cost of electricity the utility would otherwise purchase, and this change has been implemented in the analysis. Note that the cost of emissions from natural gas fuel cells is still not represented in the analysis. Even if fuel cells would have to purchase CO2 allowances based on their total emissions, ratepayers are not responsible for paying for emissions associated with NEMFC generation, so it would be inappropriate to include this cost in the analysis.

6. The resource balance year should be changed

A number of parties commented that the base case resource balance year should be changed either earlier or later. The base case analysis uses an assumption of 2017 based on the current year assumed in the development of avoided costs. There are a number of factors cited as the reason to change the resource balance year. On the side of arguing earlier is the fact that distributed generation has been a part of the load forecast in prior planning cycles, and therefore has avoided installed capacity. On the side of arguing later is the fact that California has a significant excess in available generation capacity as well as projects planned for reasons other than capacity (including RPS, once-through cooling, and SONGs replacement), and therefore additional NEM generation does not in fact avoid construction of new generation until after 2020. Given the uncertainty in what ratepayers would otherwise be paying for in terms of generation capacity, we maintain the base case assumption of a 2017 resource balance year and use sensitivity analysis by applying 2007 and 2025 resource balance year assumptions for the high and low sensitivity cases respectively.

7. Concerned substation load was not converted to TMY

The substation load was converted to typical meteorological year. A sentence has been added to the report to note this.

8. A high-voltage transmission deferral component should/should not be added to the avoided cost calculations

Proponents of a high-voltage transmission avoided cost component are correct that NEM DG could theoretically provide value by promoting the deferral of bulk transmission projects. Indeed, E3 has led numerous project-specific analyses of demand-side programs as alternatives to traditional wires investments, with seminal projects and papers dating back over twenty years. However, it is also our experience that recent and future bulk transmission projects are predominantly required for reasons other than meeting customer peak load growth. For example, changes in network topology, generator retirements, and the need to interconnect and deliver new grid-scale renewable resources are common drivers that would require transmission projects, regardless of load growth changes.

In a review of the 2011/2012 and 2012/2013 CAISO Transmission Planning Process cycles, only 1 of 71 identified transmission upgrade projects planned through 2021 cited load growth as the reason for the upgrade. Moreover, bulk transmission marginal costs, in the years when bulk transmission was driven more by peak load growth, were generally quite low --- in the $10 to $15 per kW-yr range. Because of the paucity of load-growth driven bulk transmission projects currently planned in California, and the historical low avoided cost value of such projects, we continue to assume an avoided cost of zero for bulk transmission.

9. **T&D marginal costs do not match the most recent SCE and SDG&E GRC marginal costs; Cost of Service and Avoided Costs use different T&D marginal cost values**

   For the avoided cost analysis, we use substation-level marginal transmission and distribution costs, which cannot be found in the latest GRC filings. We received this data through utility data requests. It was, to our knowledge, the most recent data available at the time.

   For the 2011 cost of service analysis, we use the T&D marginal costs that were provided by utilities from their GRCs along with the corresponding EPMC factors. The most "correct" T&D marginal costs in this scenario are the ones that match the EPMC factors. Taking T&D marginal costs and EPMC factors from different sources is ill-advised because it is the relationship between the two data sets that is the most important in terms of accuracy.

10. **There is a spreadsheet error in the allocation of capacity costs in the E3 Avoided Cost Model**
    We agree that there is a rounding error in the E3 Avoided Cost Model that shifts the hours by one. This error has been fixed, and results have been recalculated.

11. **SONGS should be removed from the resource balance year calculation**

    The shut-down of SONGS does reduce the current capacity available in California. However, there is a significant effort to procure replacement capacity through new generation and preferred resources. Therefore, we maintain the capacity of SONGS (or its replacement) in the assessment of resource balance year and rely on sensitivity analysis to vary the resource balance year from high to low.

12. **Market heat rates should use post-SONGS values; SONGS should not be considered an available capacity resource**
    Similar to the impact of SONGS on resource balance year, the planned replacement of SONGS will mitigate any increase in market heat rates due to its shutdown as long as the replacement unit has a lower heat rate than the marginal generation unit.

13. **Add additional distribution/integration costs to the COS & avoided cost calculations**

The additional distribution and integration costs associated with NEM generation are uncertain, but assumed to be low in this analysis based on currently available information. During the course of this project, we requested information on the additional distribution costs from utilities associated with NEM generation but that information is not available, presumably because it is not yet a significant cost factor. If available, it is uncertain the degree these costs would reflect an accelerating of investments the utility would make anyway, or really incremental costs attributable to NEM. In terms of integration costs, we recognize that the relatively low integration costs of NEM used in this analysis reflect the increased purchases of ramping, regulation, and reserve products at market prices that generally reflect increased fuel and other energy associated costs. They do not reflect the need to purchase additional generation capacity to provide ramping or flexible capacity. California has a significant amount of flexible hydro and natural gas generation already and is planning more for other reasons including retirement of OTC and SONGS replacement. In the context of a 33% RPS by 2020, we do not have any evidence that new capital investment will be required to provide additional flexibility to the grid. To our knowledge no entity has yet demonstrated the need or been authorized for new capital to provide ramping to support a 33% RPS.

14. **The avoided RPS procurement costs are overstated**
    We agree that the information to estimate the avoided costs of renewable purchases are out dated. We updated the avoided costs to reflect the most recent cost information from the 2012 Padilla report released in 2013.

15. **Discount RPS avoided costs in years prior to 2020 because the IOUs have already procured resources to meet projected load**

    Our assumption on the impact of RPS procurement assumes a linear interpolation to 2020. This is the same approach as is used in the calculation of energy efficiency avoided costs and reflects the fact that excess renewable procurement can be ‘banked’ and therefore displace future RPS purchases if the utilities are more than in compliance during a compliance period leading up to 2020.

16. **NEM generation increases the need for flexible capacity; this should be included as a cost, and the capacity additions should be added to the supply stack**
    There are two components of the cost of flexible capacity. The first component is an increased operational cost for additional regulation and reserves to provide the capacity. This cost is included in the analysis as the cost of integration. The second component would be the cost of buying new power plants to provide that flexibility if existing generation does not provide enough. This second component is the topic of much interest and research, including with the E3 team. Currently, we do not have any evidence that California needs new flexible capacity to meet the requirements of NEM generation through 2020 with the backdrop of a 33% RPS.

17. **The approach to valuing capacity prior to the resource balance year artificially inflates the annual capacity value**

    Perhaps, though forecasting the market price of capacity with publicly available information is difficult in California's bilateral resource adequacy market. In fact, there are many prices of capacity, one for each resource, and that information is proprietary. Therefore, we use the same approach to approximate the marginal capacity cost as is used for energy efficiency and other distributed generation. While the trajectory over time may not be knowable, we believe that the general trend is correct; as California approaches its need date for capacity we assume that market prices will approach the cost of a new capacity resource.

Comments on the Calculation of Avoided Bills

18. **Residential minimum charges should be included in the bill calculations**

    Technically, this is true. Our current analysis does not include minimum bill charges. We excluded them because they are actually very complicated to estimate accurately, and they are very small relative to the overall bill savings. Our 'back of the envelope' estimate is similar to the estimate presented by TASC which is $6.5 million dollars in additional utility revenue at the 5% NEM cap per year. This compared to the bill savings of approximately $2.2 billion per year in total bill savings is negligible.

19. **The GHG costs used in retail rate escalations are too high because they do not assume return of GHG allowance revenues**

    The retail rate escalations in the LTPP proceeding cited do assume that GHG allowance revenues are returned to ratepayers. As a result, we believe that the GHG costs used in the escalations are not too high.

Comments on the Full Cost of Service

20. **The SDG&E distribution capacity cost allocation should be justified**

    The cost of service analysis aims to mimic the way by which the utilities calculate cost of service. For the cost of service calculations, we used, to the extent possible, the capacity cost allocation methods that each utility uses themselves. The capacity cost allocation method that we use for SDG&E is the method that SDG&E believes is the most accurate and the one that SDG&E prefers to use for internal purposes. Note that the way that SDG&E allocates capacity cost for rate design may differ from the way SDG&E allocated capacity cost in their cost of service calculations. Rather than try to justify the utility approach for using more of the full cost of service based on gross customer load, we have renamed the case 'Utility Case' to properly reflect the source of the assumptions. We then do a 'Low' sensitivity analysis that assumes more cost components would be allocated costs based on net consumption and a 'High' sensitivity analysis that assumes more cost components would be allocated costs based on gross loads.

21. Gross regulatory items should be used in the net cost of service calculations

It is true that the installation of NEM generation will not reduce the total regulatory item revenues that would need to be collected from all utility customers. It is also correct that there are no avoided costs for those regulatory items when customers consume less electricity. However, the full cost of service analysis is not focused on changes in avoided cost of service --- there is a separate analysis that addresses that question. Rather, the full cost of service analysis aims to estimate what customers would have paid based on 2011 tariffs compared to what they would have paid under a full cost of service revenue allocation and rate design in 2011.

There is no cost allocation process for those regulatory cost items. Those costs are simply collected on a uniform dollar per kWh basis from all customers based on net customer usage. It would be inconsistent with current practices to assume that NEM accounts would be assigned regulator item costs based on their gross usage. Moreover, if we were to speculate that costs would be assigned in a gross fashion in the future, then the logic would necessarily need to be applied to other actions that customers take to reduce usage such as energy efficiency and even conservation. Such postulation is beyond the scope of this analysis.

However, we do recognize that this approach creates a cost shift from those customers with NEM to non-NEM customers. The analysis of bill savings by component in the study provides the details of exactly how much is shifted for each specific regulatory item.

22. Confirm that the cost of service model uses EPMC scalars correctly

We did use EPMC factors for SCE that varied by class/schedule and function. We have also rewritten footnote 23 (previously footnote 20) to clarify this.

23. Cost of service should use gross load to calculate subtransmission and transmission costs in SCE's Base Case

Our approach for the "Base Case" cost allocation has been to mimic as much as possible the current utility approach and allocating some cost components based on gross usage, and others on net usage as defined for each utility. Therefore, we have updated the cost allocation as suggested to conform with SCE's practice. At the same time, and as described above with respect to SDG&E, we changed the name of the case previously referred to as the "Base Case" to "Utility Case." We then did sensitivity analysis with a "Low" case that allocates more costs based on net usage, and a "High" case that allocates fewer.

Requests for Report Clarification and Additional Analysis

24. Publicly release data and/or SAS codes

The CPUC confidentiality rules prohibit public release of confidential utility information.

25. Add a sensitivity in which NEM is valued at 100% of the renewable premium

This change would reflect a different policy whereby ratepayers own the renewable attribute of the NEM generation rather than the host customer. The CPUC has considered this and the Commission adopted a set of rules where the host customer owns the renewable attributes of their systems. As a thought experiment, this analysis could be easily done using the sensitivity features in the publicly available tool.

26. Add a sensitivity with the assumption that the RPS is raised to 50% by 2030

Assessment of a 50% RPS by 2030 is beyond the scope of this analysis.

27. Perform a PAC and/or TRC test; analyze participant and/or societal impacts

Cost-effectiveness tests and impacts outside of those required by AB 2514 are outside the scope of this analysis. However, the CPUC has done these analyses for specific renewable technologies such as rooftop solar in the past and those studies are available online. The reason we do not do participant or societal cost test analysis of the renewable generation is because they answer very different questions. The PAC test measures the financial return to participants under the NEM rule, and the TRC and Societal Test ask a broader question of whether California should be investing in specific renewable technologies as a society. As explained in the workshop, we believe California policy is largely past the question of <u>*whether*</u> to do solar which is the focus of the TRC and SCT, and is focused on <u>*how*</u> to do solar without shifting costs to those who do not or cannot do solar themselves.

28. Explain substation allocator aggregation to climate zones

We aggregate substation loads to climate zones solely for the purposes of creating a manageably-sized data set for display in the E3 Avoided Cost Model. The actual avoided cost calculations used in the NEM analysis uses substation-level data without aggregation. In terms of the aggregation method, a GIS substation shape file from the CEC is mapped to a climate zone shape file. To reiterate, this method is used only to aggregate data for public display in the E3 Avoided Cost Model. See footnote 35 on p. C-44.

29. Display annual NEM impacts over the 20-year period

This analysis is not difficult using the publicly available tool, however, we did not add it to the report because we do not believe it adds much insight to the analysis. Since we fix the retail rate design in all years to the 2011 rate design, and limit penetration to the 5% NEM cap, the cost shift beyond 2020 would be driven by our assumption of retail rate escalation and forecast of future avoided costs, both of which are highly uncertain.

30. Report results by rate schedule in the body of the study

We added tables with the number of customers, bill savings, avoided costs, and program costs by rate schedule in the E3 NEM Summary Tool. The results are not included in the report, as they are not a key finding of the analysis, but they are available for viewing in the public model.

31. The high avoided cost case has lower avoided capacity costs than the base and low cases

Because the high gas price forecast used in the high avoided cost sensitivity results in higher energy market prices, the capacity value in the high avoided cost case is lower than the capacity value in the base avoided cost case.

32. Vintaged ELCC should be clarified and used in the Base Case

Clarification of the assumptions have been added to the report. In the Base Case of the NEM analysis, we assign all generation ELCC values based on their contribution to load reduction in the year of the generation analyzed regardless of when the system was installed. For example, in the 2020 Snapshot analysis, all generation is assigned the 2020 ELCC value. In the 2012 Lifetime Analysis, the ELCC value of the generation from a system installed in 2012 decreases over time: all generation in 2012 receives the 2012 ELCC, all generation in 2013 receives the 2013 ELCC, etc. Note that all generation after 2020 is valued at the 2020 ELCC. The Base Case represents the contribution of a NEM generator to system capacity given the whole portfolio. If payments were made to renewable generators based on their ELCC this would be the payment amount.

We recognize that with this approach, additional renewable resources installed later can erode the capacity value of a NEM resource if they have similar output profile. Therefore, we included a sensitivity in which all NEM systems receive the 2013 ELCC value. Since the 2013 ELCC value does not differ substantially from the ELCC values prior to 2013, this case is meant to give a high ELCC value to all of the NEM generation.

33. Include a summary of results and limitations of the report, including a list of caveats

The draft report includes a summary of results in the Executive Summary and there is a discussion of limitations and caveats at many points in the report and appendices where appropriate.

34. Change the framing of the cost of service results and/or the terminology used in this section

We aim to be as objective as possible in its presentation of the cost of service results. A few changes have been made to the cost of service text where we agree that the previous text was misleading, but no changes that might detract from the objectivity of the analysis have been made.

35. Add a discussion of A.B. 327

The potential impacts of A.B. 327 are outside the scope of this analysis. Moreover, A.B. 327 was not signed into law until after the draft report was completed. The CPUC Energy Division introduction does include a discussion of these potential impacts.

36. Calculate the cost of service results using the median contribution from NEM customers rather than the average

We believe that the aggregate cost of service results and the median contribution from NEM customers are both informative. A section on the median cost of service results has been added to the report along with the existing aggregate results.

37. Provide a breakout of the cost of service results by dwelling type

We do not have the data to perform this analysis.

38. Eliminate the characterization of behind-the-meter generation and consumption as energy efficiency

We agree that, although many similarities exist between energy efficiency and behind-the-meter renewable generation and consumption, there are also many key differences between these two types of load reduction. We have removed the misleading characterization from the report.

39. There is a sentence with incorrect information concerning the income analysis

This sentence has been updated and removed from various sections of the report, as appropriate.

40. Provide a breakdown of the income results by decile

We received income data from each of the IOUs in different forms. The only consistent percentile anchor across these data sets is the 50^{th} percentile. We could show more granular income results for each utility, but these results would not be easy to aggregate or to use for comparisons across IOUs.

41. Explain how rate design changes since 2010 have impacted results relative to the 2010 study results

The most impactful rate design change was a reduction in the highest cost PG&E tier which reduces the cost-shift in this study relative to the 2010 study. However, as discussed in the report, there are several other moving pieces, including a reduction in avoided costs that reduce the value of NEM generation, projections of future retail rates, and utility cost of financing. Overall, the benchmarking in the report compared to 2010 indicates that the cost-shifts are comparable overall and the details are presented in the report.

42. Tables 4 and 5 on page C-26 are identical

We have updated these tables with the correct loss factors.

Requests to Change Analysis Methodology (Out of Scope)

The comments on changes to methodology were beyond the scope of those requested by the CPUC. In addition, many of these talking points were addressed during the stakeholder workshops. However, we provide short responses.

43. Eliminate or reframe the Export Only or All Generation analyses

We think presenting both cases provides valuable information to the study. AB 2514 does not prohibit the inclusion of additional information.

44. Use current rates instead of 2011 rates

The choice of 2011 rates was made to be consistent with available utility billing data. The study and data requests for this analysis were started mid-year 2012, and we could forever be updating the many rates in the analysis. Despite the vintage of the rates, we are not aware of significant changes that would dramatically affect the results. Given the passage of AB 327, it seems likely that there will be a future process to evaluate the cost-shifts of different rate designs, and we believe this study provides a solid foundation for that future analysis.

45. The study should use existing methods to allocate generation and distribution capacity costs

We feel that the new methods for allocation of generation and distribution capacity costs are much more accurate and use much better data and information. This change was made in response to a broad set of stakeholder comments in November and December 2012. We recognize that it comes at the price of some complexity and stakeholder transparency.

46. CARE customers should be excluded/included from the IOU median household income calculation

We don't understand what a comparison of household incomes of NEM customers to non-CARE customers adds to the analysis. The idea is to compare NEM customers to all customers which include both CARE and non-CARE customers to see what segment of the California population overall participates in NEM.

47. The 2012 lifecycle analysis should be emphasized more in the report

We have added language to the report to clarify the 2012 lifecycle analysis.

48. Median income of homeowners in CA should be used instead of median CA household income in the income analysis

We don’t have the data to be able to do this analysis, and furthermore, we believe the analysis we have done appropriately reflects the household income disparity in NEM participation that is caused in part by the limited ability of non-homeowners to participate in NEM.